OPPORTUNITIES FOR HYDROGEN-BASED ENERGY STORAGE FOR ELECTRIC UTILITIES[1]

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Abstract

One potential market opportunity for hydrogen is the use of hydrogen as an energy storage mechanism for electric utilities. Electric utilities can use stored energy in a variety of applications. One important potential application for energy storage is to improve load management. This can include both matching variable renewable energy sources with electricity demand and also leveling available electricity production capacity across off-peak and on-peak demand times. Hydrogen used as an energy carrier might hold promise for these energy storage applications.

In this study, we investigate the potential for using stored hydrogen for load leveling and renewables matching in the electric sector. In this application available electricity capacity and renewable energy resources will be used to produce hydrogen, which can then be converted back to electricity during peak demand hours. A hydrogen-based storage system will include several basic system components, including an electrolyzer system to produce hydrogen via water electrolysis, a hydrogen storage system, and a system to convert stored hydrogen back into electricity for use in meeting peak electricity demand.

Several basic system configurations are investigated, including the use of either steel tanks or geologic caverns for hydrogen storage, and the use of either hydrogen-fueled internal combustion engines or fuel cells for converting stored hydrogen into electricity. The study considers three timeframes: near-term, mid-term (2010-2020), and long-term (2020-2030). For each basic configuration, an optimized system is modeled based on consideration of the capital costs, operating and maintenance costs, replacement costs, and efficiencies of each of the subsystem components.

This study finds that on-peak electricity can be produced using a stored hydrogen system in the near-term for 28 to 51 cents per kilowatt-hour. In the long term, mature and fully optimized hydrogen technologies can allow hydrogen-based energy storage systems to store electricity for as little as 16 cents per kilowatt-hour.

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1. Background

Electric utilities can use energy storage to meet a variety of goals. For instance, energy storage can be used to improve power quality, to provide peaking power, to provide additional spinning reserves, and for load management. In general, using stored energy can help optimize and stabilize electric utility supply, transmission, and distribution systems. Advancements in energy storage technologies have enabled energy storage to play a role in grid stabilization and reliability, power quality, and load shifting [1].

Overall, energy storage is an increasingly common element of electric utility power systems, providing a variety of benefits. The use of energy storage can avoid the need for additional peaking power units which may have poor capacity utilization, higher emissions, and poor fuel efficiency. Energy storage provides a means for load management, allowing a time-shifting of energy and capacity. As such, energy storage can enable low-cost energy produced during periods of low demand to provide electricity during periods of peak demand when the value of electricity is the highest. Additionally, the use of stored energy can reduce the need for spinning reserves which may increase the fuel efficiency of baseload systems and increase their capacity utilization.

Recently, energy analysts and policymakers have begun to view energy storage as a key enabling technology for the increased use of renewable energy resources for electricity generation. Renewable energy sources such as solar and wind are inherently variable in their output. Additionally, the peak times for solar and wind energy production may not match peak demand hours for electricity. For example, wind energy production is typically skewed toward off-peak hours, with greater wind energy available at night when demand is low. Energy storage can enable renewable energy resources to be better aligned with energy demand.

The value of energy storage used for load management and renewables matching depends on the particular economics of an electric utility's production system. This value will be driven by the particular load profile for which the utility must provide electricity coupled with the production capital the utility employs to meet that demand. Differences between hourly demand levels, and thus on-peak and off-peak electricity prices, provide an opportunity for energy storage.

While each utility service area is unique, an analysis of a utility's hour-by-hour marginal costs will generally show that a certain percentage of electricity demand is met at a very low cost, on the order of 2-3 cents per kilowatt-hour or less. Beyond that, the marginal cost of production increases from 4-5 cents per kWh to 10 cents or more per kWh. The lower cost electricity generally is produced by baseload systems, while the more expensive electricity is generated by peaking units. Energy storage can be used to store energy produced at low cost and re-convert that stored energy to electricity, displacing higher marginal cost peaking power.

For instance, off-peak electricity demand might be met with production via coal baseload units, while on-peak demand would be met with a mix of coal baseload production and natural gas turbine peaking units. In such an instance, the case for investing in energy storage becomes stronger as natural gas prices increase, thereby increasing the cost of natural gas-based electricity production. In general, energy storage systems, even with substantially higher initial capital costs, may compete with natural gas turbines since storage systems tend to have lower variable costs.

Hydrogen might hold promise for these energy storage applications. Hydrogen is an energy carrier rather than a primary source of energy. Once produced, hydrogen becomes a fuel source that can be converted to electricity using a fuel cell or hydrogen-fueled internal combustion engine. Hydrogen can be produced in a number of different ways. For the electric utility sector, the production method of greatest interest is hydrogen production via the electrolysis of water using electricity to provide the necessary energy for the reaction. In the electrolytic conversion of water into hydrogen, an electric current is passed through an anode and a cathode in contact with water. The net reaction which occurs is:

$$2H_2O_{liquid} + \text{electricity} \rightarrow 2H_2 + O_2$$

With perfect efficiency, this reaction requires 39 kWh of electricity to produce 1 kilogram of hydrogen at 25° C and 1 atmosphere. Again, with perfect efficiency this kilogram of hydrogen could be re-converted back into 39 kWh of electricity. In reality, neither the conversion of water into hydrogen nor the conversion of hydrogen back into electricity will be perfectly efficient. Understanding the cost of using hydrogen as a storage mechanism will therefore depend both on the cost of this storage system and on the conversion efficiencies of the necessary subsystems.

2. Purpose of the Study

This study investigates the use of hydrogen as a means of energy storage to better integrate renewable solar and wind resources into the electricity production mix, as well as to help level available electricity production capacity across off-peak and on-peak demand times. Specifically, this study assesses the cost of producing electricity from a hydrogen-based energy storage system. In such a scenario, renewable energy and/or off-peak electricity would be used to produce hydrogen that could be stored and re-converted back to electricity in times of higher demand. In this way, hydrogen could be used as the mechanism for load leveling and for matching renewable energy to electricity demand.

This investigation is meant to be a scoping study to better understand the potential costs of using hydrogen as an energy storage mechanism by electric utilities. This study is not a cost assessment of a particular hydrogen-based energy storage system design. Instead, this study uses costs and performance assumptions for subsystem components based on existing U.S. Department of Energy (DOE) models and targets. This analysis models the costs and performance of a number of theoretical systems that might be assembled to create hydrogen through water electrolysis, store the hydrogen, and then re-convert the hydrogen back into electricity. In general, such systems will include several basic elements, as depicted in Figure 1. System elements include:

- The electric grid
- Renewable energy inputs
    - Solar (photovoltaic), wind
- An electrolyzer
- Hydrogen storage
    - Steel tanks, geologic storage
- Hydrogen-to-electricity conversion
    - Fuel cells, hydrogen internal combustion engine

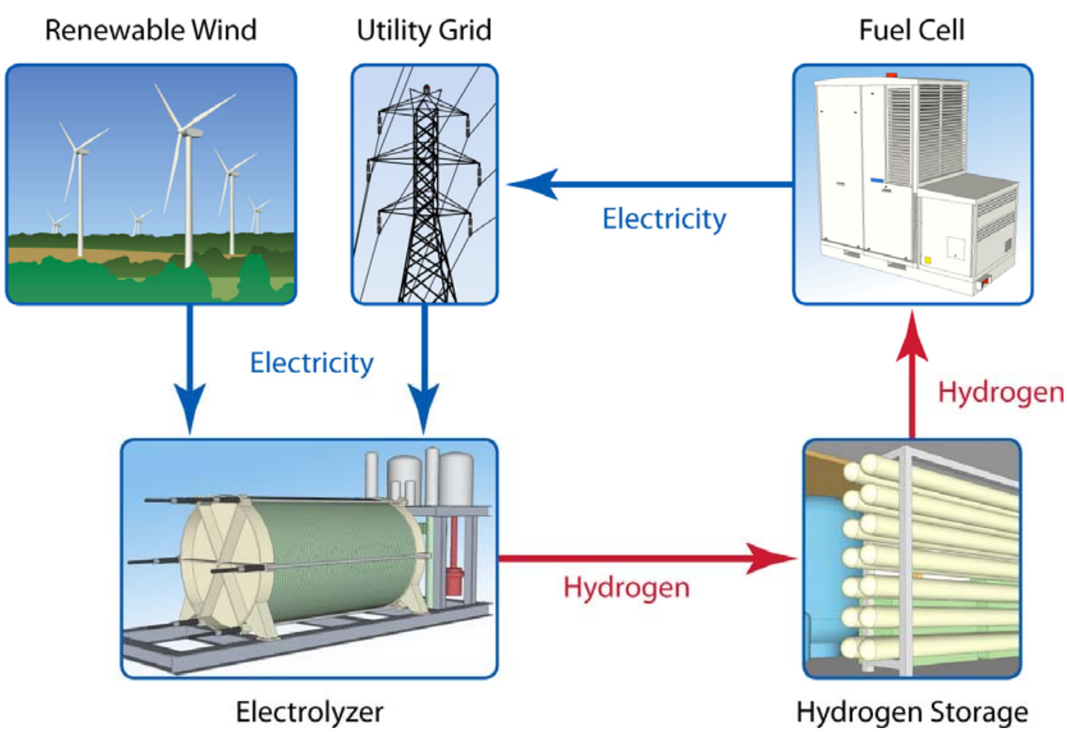

Figure 1. Elements of a Hydrogen Energy Storage System

Understanding the value of a hydrogen-based storage system requires a comparison to other electricity production options such as natural gas peaking units. At the same time, hydrogen as a storage mechanism must compete with other storage system technologies. There are a number of electricity storage technologies that might be employed for load leveling and renewables matching applications. These include:

- Battery storage systems including conventional lead-acid batteries and more advanced battery technologies such as sodium-sulfur (NaS) batteries
- Compressed air energy storage (CAES), which uses off-peak electricity to compress air that is stored in aquifers or salt caverns
- Pumped water storage, which pumps water from a lower reservoir to a higher reservoir enabling hydro-electric energy production when the water is released to the lower reservoir at a later time [2].

To help understand how hydrogen-based energy storage compares to other alternatives, this study analyzes the cost of electricity storage from a number of idealized hydrogen storage systems. By considering the costs and system efficiencies of the various sub-system components, an estimated cost of on-peak electricity production based on stored hydrogen is determined.

3. Modeling Approach

This analysis follows the approach used in Levene, Kroposki, and Sverdrup, 2006 [3]. In that study, researchers at the DOE's National Renewable Energy Laboratory (NREL) investigated whether hydrogen for transportation fuel use could be economically produced using wind power. That analysis used information on the electricity sector provided by Xcel Energy.

This current study will follow the methodology developed in the previous NREL study and will use many of the same cost assumptions for electricity costs as well as capital and operating costs.

<u>HOMER Model</u>

As with the 2006 study, this analysis will use the HOMER model (hereinafter "Model") for system optimization and calculation of electricity cost [4]. The Model was developed at NREL to allow users to optimize the configuration of electricity production systems and to easily evaluate the many possible configurations of these systems. For example, when designing an electric system to meet a 50 MW load for an hour every day, the Model can answer questions such as: should the system have enough gas turbines so that each hour always has 50 MW, or should battery storage be added, or should a diesel engine be employed – and which of these options costs less?

The HOMER model is an excellent tool for analyzing electric systems on an hourly basis. For this study, system components, available energy resources, and loads are modeled hour by hour for a single year, with energy flows and costs held constant over a given hour. The Model requires inputs such as subsystem component options and performance, capital and replacement costs, fuel and electricity costs, and resource availability. The Model uses these inputs to simulate different system configurations, and generates a list of feasible configurations sorted by net present cost (NPC). The Model also reports the cost of energy produced for each feasible system configuration, reported on a $/kWh basis. As the systems modeled in this study always produce the same amount of electricity, the system configuration with the lowest net present cost is also the configuration with the lowest cost of electricity. As such, the system configuration with the lowest COE is determined to be the most economic solution.

The Model defines the levelized cost of energy (COE) as the average cost per kWh of useful electrical energy produced by the system. To calculate the COE, the Model divides the annualized cost of producing electricity (the total annualized cost minus the cost of serving the thermal load) by the total useful electric energy production. The equation for the COE is as follows [5]:

$$COE = \frac{C_{ann,tot} - c_{boiler} E_{thermal}}{E_{prim,AC} + E_{prim,DC} + E_{def} + E_{grid,sales}}$$

where:

$C_{ann,tot}$ = total annualized cost of the system [$/yr]

c_{boiler} = boiler marginal cost [$/kWh]

$E_{thermal}$ = total thermal load served [kWh/yr]

$E_{prim,AC}$ = AC primary load served [kWh/yr]

$E_{prim,DC}$ = DC primary load served [kWh/yr]

E_{def} = deferrable load served [kWh/yr]

$E_{grid,sales}$ = total grid sales [kWh/yr]

Because the system in this study does not serve a thermal load ($E_{thermal}$=0), this term will equal zero. Likewise, in this study, we only consider AC primary load served. Thus, for the system modeled in this study, the cost of electricity is simply the total annualized cost of the system ($/yr) divided by the total primary AC load served (kWh/yr).

4. Storage Systems Considered

As described above, a generalized hydrogen-based storage system consists of a few basic components including the electric grid, an electrolyzer system to produce hydrogen using renewable energy and off-peak energy, a hydrogen storage system, and a means to convert stored hydrogen back into electricity to satisfy on-peak demand (see Figure 1). This analysis investigates three different potential configurations of such a hydrogen-based storage system. For all cases, the modeled system includes the electric grid, renewable energy for purchase off the grid, and an electrolyzer system to produce hydrogen. The three cases vary in the selection of the hydrogen storage subsystem and the hydrogen-to-electricity conversion unit.

For Case 1, the modeled system assumes that the hydrogen storage system is built using readily available steel storage tanks. In this system, each storage tank is capable of storing 85 kg of compressed hydrogen gas. The complete storage system consists of several hundred of these steel tanks. For this case, conversion of stored hydrogen back into electricity is accomplished using a hydrogen-fueled internal combustion generator. Again, this type of hydrogen "genset" is readily available today. (See Figure 2 for a schematic of the system components of Case 1.) Given the cost and performance of this system compared to the other systems considered, this case represents a fairly conservative upper bound on the cost of electricity produced from stored hydrogen.

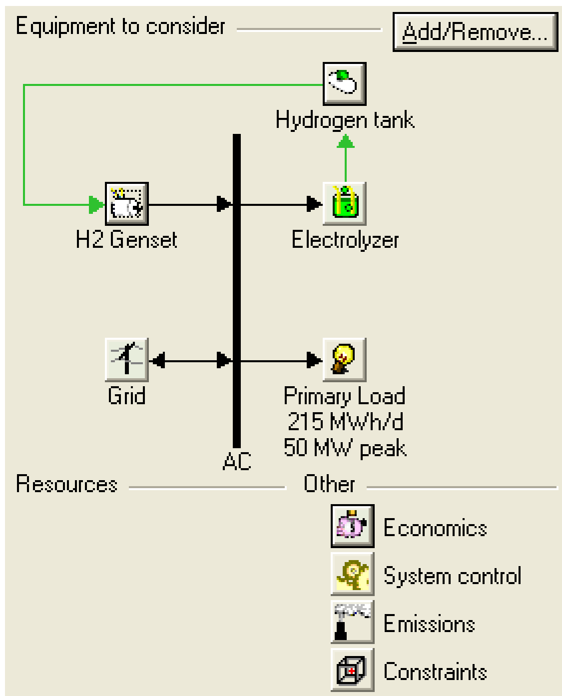

Figure 2. Case 1 System Schematic

For Case 2, the configured system again assumes the use of a steel tank storage system. Converting stored hydrogen back to electricity in this case is accomplished with a hydrogen fuel cell. The fuel cell system modeled has conversion efficiencies in the range of 60%-70%, which are significantly better than the efficiencies of the hydrogen internal combustion generator modeled in Case 1. (See Figure 3 for a schematic of the system components of Case 2.)

For Case 3, the configured system is based on using a hydrogen fuel cell subsystem for converting stored hydrogen into electricity, as was modeled in Case 2. For this case, however, the steel tank hydrogen storage system has been replaced with underground geologic storage. That is, this case models the use of underground salt caverns to store compressed hydrogen gas.

In general, geologic hydrogen storage is considerably cheaper than storing hydrogen in steel tanks. While systems using geologic storage can be more difficult to site compared to systems using steel tanks for storage, the modeling of the longer-term costs associated with Case 3 presents a reasonable lower-bound or best-case cost of producing electricity with stored hydrogen.

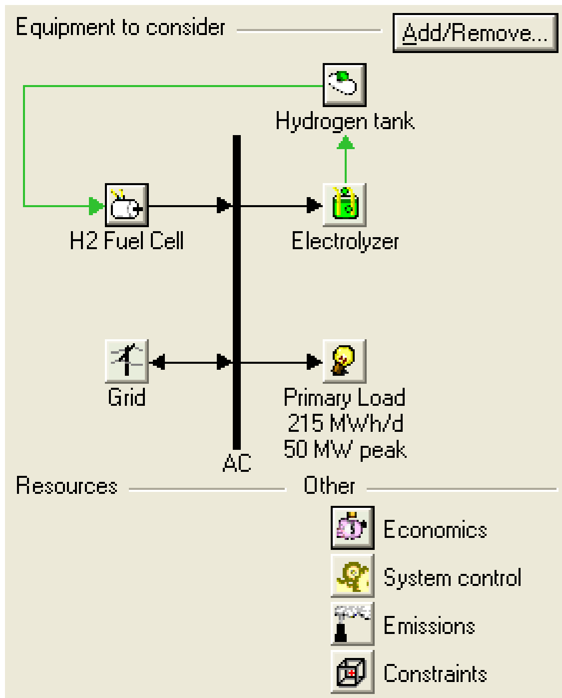

Figure 3. Case 2 System Schematic

For each of the three cases, the cost of electricity produced from stored hydrogen was analyzed for three different timeframes: near term, mid term, and long term. The costs and efficiencies of the equipment modeled changes for each of the timeframes. The timeframes used are defined as follows:

- Near term = today until 2010
- Mid term = 2010 – 2020
- Long term = 2020 – 2030

The long term case may be considered to be the best-case scenario in the future, representing the lowest projected cost of electricity production from stored hydrogen when hydrogen system technologies are optimized and mature.

5. Assumptions Used in the Study

The study models hydrogen-based energy storage systems capable of producing 50 MW of electricity for six hours each weekday to meet additional on-peak demand. Under this model, no hydrogen will be produced by the system during these peak hours of electricity demand. Conversely, all of the 50 MW of on-peak demand is modeled to be produced from electricity generated from stored hydrogen.[3]

The system modeled assumes there is no electricity demand needing to be met with stored energy during the 18 off-peak hours each weekday, or any demand during weekends. During these non-peak hours, the energy storage system can be "charged" by producing and storing hydrogen. The energy used to produce this hydrogen via water electrolysis is assumed to come from available renewable resources as well as available baseload generating capacity. The model assumes that the cost of this "non-peak" electricity is $0.038 per kWh. This cost reflects Xcel Energy's purchase price of wind electricity at the time of the Levene, et al. 2006 study. (The current study uses the same wind electricity purchase price so the results of this study are comparable to the findings of the 2006 study.) Additionally, this study also considers the cost of non-peak electricity at $0.025/kWh and $0.049/kWh as sensitivity cases.

In addition to these assumptions regarding the scope and set up of the electrical system, this analysis makes a number of assumptions regarding subsystem costs and efficiencies. Table 1 outlines these major assumptions. In general, these assumptions are based on previous modeling efforts conducted by NREL and on the projections from DOE hydrogen and fuel cell programs. Overall, this analysis models subsystem capital costs, replacement costs, fixed operating and maintenance costs, and fuel and electricity costs.

The electrolyzer subsystem used to produce hydrogen from non-peak electricity is modeled based on a bi-polar alkaline electrolyzer design. The costs associated with this subsystem and its performance are based on DOE's H2A (hydrogen analysis) Production model [6]. Uninstalled costs for this electrolyzer system range from $675 per kilowatt capacity in the near-term to $300/kW in the longer term. Conversion efficiencies for the electrolyzer system range from 73% in the near term to 87% in the long term (on a higher heating value basis).

The steel tank hydrogen storage subsystem and the geologic hydrogen storage subsystem are modeled based on information from the upcoming version of DOE H2A Delivery Components model [7], together with information from the DOE Hydrogen Multi-Year Program Plan [8]. Steel tanks are assumed to cost $900 per kilogram of storage in the near term to $345 per kilogram in the long term, with hydrogen stored at 2,500 psi. Costs for the geologic storage system are not linear, but range from about $80 per kilogram to $120 per kilogram. (Cost curves for the Homer model were built using several storage sizes consistent with the storage needs for the three cases modeled.) Both types of hydrogen storage subsystems require compressors to pressurize the hydrogen gas for storage, with costs dependent on size, pressure of storage, and timeframe modeled. Additionally, the

[3] The decision to model 50 MW of electricity during six on-peak hours was developed in conjunction with Xcel Energy to align this study with a generalized study of the value of energy storage that is currently being conducted by Xcel.

storage subsystem will require additional energy input to run the compressors. Compressors for the steel tank storage subsystem are assumed to use 1.2 kilowatt-hours per kilogram of hydrogen stored, and geologic systems, which have a lower maximum pressure of 1,800 psi, require 1.1 kWh per kilogram.

Table 1. Major Assumptions Used in the Study

Parameter	Assumption		
Peak Electricity	• Peak electricity usage is from 1-7 pm on weekdays • Weekend hours are all off-peak • On-peak demand is 50 MW • The electrolyzer cannot produce hydrogen during peak hours		
Non-Peak Electricity	• Utility capital and operating costs for electricity generation are not modeled • Non-peak electricity is priced at the cost of wind electricity • Wind electricity is purchased at a rate of \$0.038/kWh		
System Pressure	• Hydrogen is compressed to 2500 psi for steel tank storage and 1800 psi for geologic storage		
Compressor Energy Req't	• 1.2 kWh/kg hydrogen for steel tank storage • 1.1 kWh/kg hydrogen for geologic storage		
Electrolyzer Capital Costs	Near term: \$675/kW	Mid term: \$400/kW	Long term: \$300/kW
Electrolyzer System Efficiency	73%	81%	87%
Fuel Cell Capital Costs	\$750/kW	\$400/kW	\$325/kW
Fuel Cell System Efficiency	60%	65%	70%
Steel Tank Capital Cost (28,600 kg nominal storage)†	\$30.7M	\$19.7M	\$12.3M
Geologic Storage Capital Cost (28,600 kg nominal storage)†	\$7.8M	\$6.8M	\$5.8M
Internal Rate of Return	• 10% real rate of return assumed for all investment costs		

†Storage system capital costs include the cost of the necessary compressor subsystem.

The fuel cell subsystem is modeled based on targets from the DOE Solid-state Energy Conversion Alliance (SECA) program [9].[4] Costs of the fuel cell subsystem are assumed to be \$750 per kilowatt (uninstalled) in the near term, \$400/kW in the mid-term, and \$325 in the long term [10]. The conversion efficiency of the fuel cell subsystem is 60% in the near term, 65% in the mid-term, and 70% in the longer term. Conversion efficiencies modeled are the total

[4] While the SECA program specifically considers solid-oxide fuel cells (SOFCs), the subsystem modeled in this study does not consider any specific fuel cell type. For the purposes of this study only the costs and conversion efficiencies are needed. For the application investigated here, phosphoric acid fuel cells may be more appropriate, but more research is needed.

net conversion efficiency, including both the direct conversion of hydrogen into electricity by the fuel cell as well as an additional “bottom” cycle of electricity production based on the thermal energy of the fuel cell system connected to necessary heat exchangers and turbines.

The analysis also includes a number of assumptions used in each case. A 40-year project lifetime is modeled for every case, though many of the subsystems have component lifetimes that are shorter than this. Component lifetimes and replacement costs are modeled for each subsystem, allowing each storage system to achieve this 40-year lifetime. The systems modeled include costs for land, labor, and indirect capital costs such as site preparation, engineering design, and project contingency. Finally, a 10% real internal rate of return (IRR) was assumed for all investment costs.

6. Results

This study investigated the cost of producing on-peak electricity using hydrogen as a mechanism to store off-peak and renewable electricity. By using electricity available during non-peak hours, hydrogen can be produced via the process of water electrolysis, stored, and then re-converted back into electricity using a fuel cell or hydrogen combustion engine to meet on-peak electricity demand. Three cases were investigated as part of this analysis. In all cases, the electrolyzer system uses off-peak and renewable electricity to produce hydrogen. The cost of this off-peak electricity is assumed to be \$0.038/kWh. In Case 1, the produced hydrogen is stored in steel tanks and is later re-converted back to electricity in a hydrogen-fueled internal combustion engine. In Case 2, hydrogen is stored in steel tanks, but hydrogen fuel-cells are used to convert the stored hydrogen back to electricity. In Case 3, hydrogen is stored in underground geologic caverns and is then re-converted to electricity in a fuel-cell. For each case, three timeframes were studied: near-term, mid-term (2010-2020), and long-term (2020-2030).

The resulting costs of producing on-peak electricity from stored hydrogen are shown in Figure 4. Electricity produced using a hydrogen internal combustion engine is the most expensive, ranging from \$0.51/kWh in the near term to \$0.23/kWh in the long term. Though hydrogen combustion engines are currently available at lower cost on a per kilowatt capacity basis compared to fuel cells, they are less efficient, resulting in a higher cost of electricity. Hydrogen-based storage systems using fuel cells rather than internal combustion engines for converting hydrogen back into electricity are able to store energy at a lower cost, as the results for Cases 2 and 3 show. Systems using steel tanks for storage and fuel cells for conversion (Case 2) can store and produce electricity for \$0.33/kWh in the near term, with costs falling to \$0.17/kWh in the long term. Analysis of Case 3 shows that systems employing fuel cells for conversion and geologic storage of hydrogen offer the lowest cost hydrogen-based energy storage, with on-peak electricity produced by these systems for \$0.28/kWh in the near term and \$0.16/kWh in the long term.

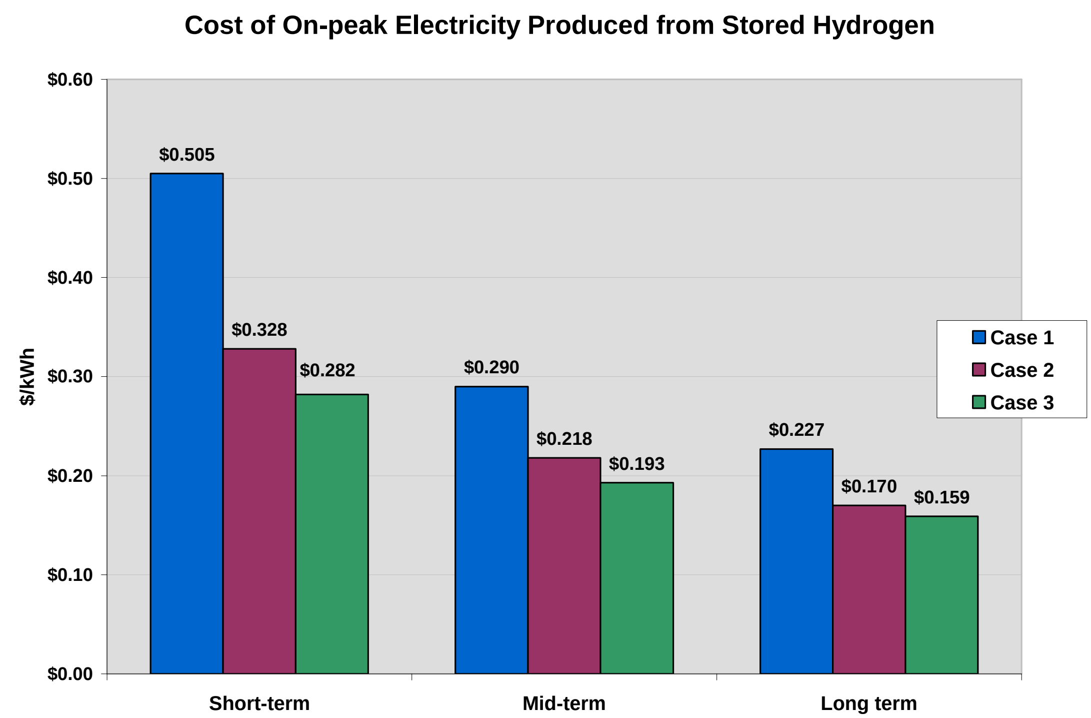

Figure 4. Cost of Electricity Produced from Stored Hydrogen

This longer term storage system configuration represents a best case scenario for electricity production from stored hydrogen, when the necessary subsystem technologies are highly mature, and thus are at their lowest cost and best performance level. While systems using geologic hydrogen provide the lowest cost of energy storage, systems using steel tanks for hydrogen storage (Case 2) are not much more expensive, with costs ranging from one cent per kilowatt-hour higher in the long term, and 3¢/kWh in the mid-term. Though slightly more expensive, these systems might be able to be sited in more places and more quickly than would systems using geologic storage.

The on-peak electricity prices are based on a number of cost factors, including: the cost of non-peak electricity used to produce hydrogen (both from available production capacity and from renewable energy sources); the capital costs of the electrolyzer, fuel-cell, and storage subsystems; the replacement costs of these subsystems; and fixed operating and maintenance costs. The costs for systems capable of producing 50 MW of electricity for six peak demand hours each weekday are shown in Table 2. Also shown is the total round-trip energy storage efficiency for each of the modeled systems. These efficiency figures compare electricity output to total electricity input, including both the energy to produce the hydrogen via the electrolyzer system and the energy required to compress the hydrogen for storage. As can be seen, round trip energy efficiency for the three cases ranges from 21% to 50%. In addition to the total capital costs shown in

Table 2, Figure 5 shows the amount of capital cost for each system on a cost per installed kW capacity basis.

Table 2. Cost and Efficiency Details for Each Case

Description	Time-frame	On-Peak $/kWh	Costs (Million $) Capital	Replace-ment	O&M	Efficiency
Case 1: H2 ICE, steel tank storage	Near-Term	0.51	176.8	33.6	42.2	21%
	Mid-Term	0.29	97.1	8.0	29.2	32%
	Long-Term	0.23	67.6	3.6	23.5	36%
Case 2: H2 fuel cell, steel tank storage	Near-Term	0.33	131.2	12.5	29.3	36%
	Mid-Term	0.22	74.9	8.7	18.5	44%
	Long-Term	0.17	52.1	6.5	15.0	50%
Case 3: H2 fuel cell, geologic storage	Near-Term	0.28	94.7	15.3	27.3	36%
	Mid-Term	0.19	55.8	9.2	17.9	44%
	Long-Term	0.16	43.4	7.0	14.8	50%

To conduct the analysis in this study, we optimized the configuration of each system studied for each timeframe using the Homer model. To accomplish this, the Homer model was configured with information on the cost and performance of each subsystem component. The Model optimized the selection of subsystem components to minimize the net present cost of the system, and hence the overall cost of electricity.

Each hydrogen-based storage system (by case and timeframe) has a resulting configuration optimization that is unique and thus the specific costs of the resulting systems are different. Figure 6 displays the costs of the storage system optimized for Case 3 in the longer term, with detailed costs shown for each subsystem component. The general make-up of these costs is fairly consistent across all the cases, however. As shown, the greatest cost of this system is the cost of non-peak electricity used to produce the hydrogen. Beyond this cost of input energy, the fuel cell system presents the largest component cost. The cost of the geologic hydrogen storage system is a small fraction of the total system cost (as is the cost of steel tank storage in Case 2). Given these costs, future improvements in the cost and efficiency of fuel-cell systems can significantly reduce the cost of on-peak electricity generated from stored hydrogen, whereas improvements in hydrogen storage systems though important will not yield a significant improvement in the overall cost of electricity storage.

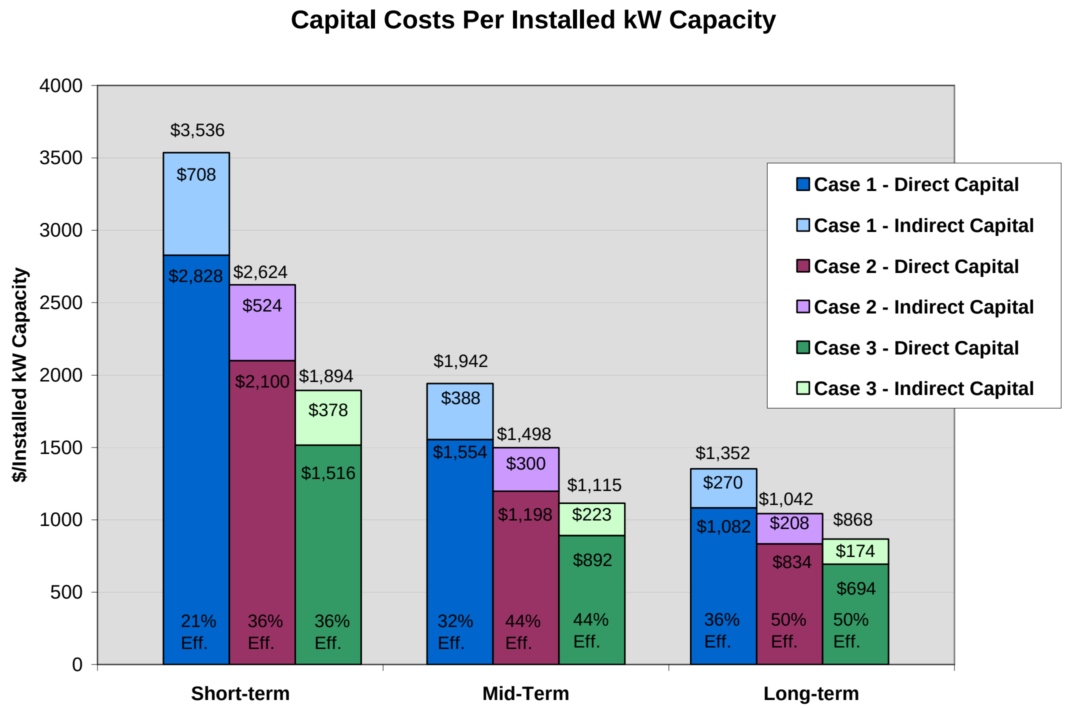

Figure 5. Capital Costs per Installed kW Capacity for the Systems Modeled

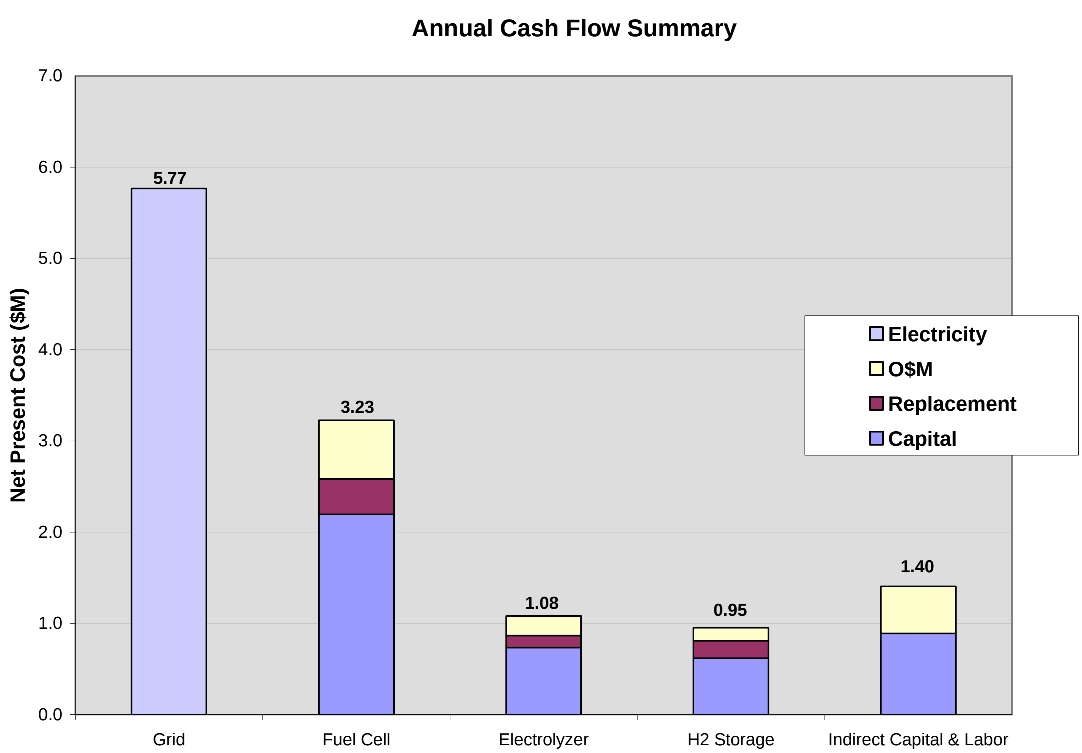

Figure 6. Detailed Cost Information for the Optimized Storage System for Case 3.

To put the costs of hydrogen-based energy storage (which range from $0.16/kWh to $0.22/kWh across the mid- and long-terms for Cases 2 and 3) in perspective, an analysis of electricity production costs developed by Xcel Energy found that that the cost of electricity production by natural gas-fired combustion turbines (CT) and advanced turbines ranged from $0.16/kWh to $0.20/kWh. These costs are based on typical system costs and utilization rates. This cost range provides a useful benchmark, as natural gas CT units are often employed to produce marginal, on-peak electricity.

The predicted electricity storage costs are sensitive to the assumptions used in the modeling, particularly assumptions on subsystem cost, performance (e.g., efficiency), and the cost of input electricity to charge the system. Comparing the resulting storage costs across timeframes provides an understanding of the sensitivity of storage cost due to assumptions of cost and performance. The longer-term case considers highly optimized and mature hydrogen technologies, with low system costs and high performance. The mid-term cases, however, use scaled back assumptions on system cost and performance. As seen above, for Case 3, the cost of hydrogen-based energy storage can still be achieved for less than $0.20/kWh, even using more moderate assumptions on system cost and performance.

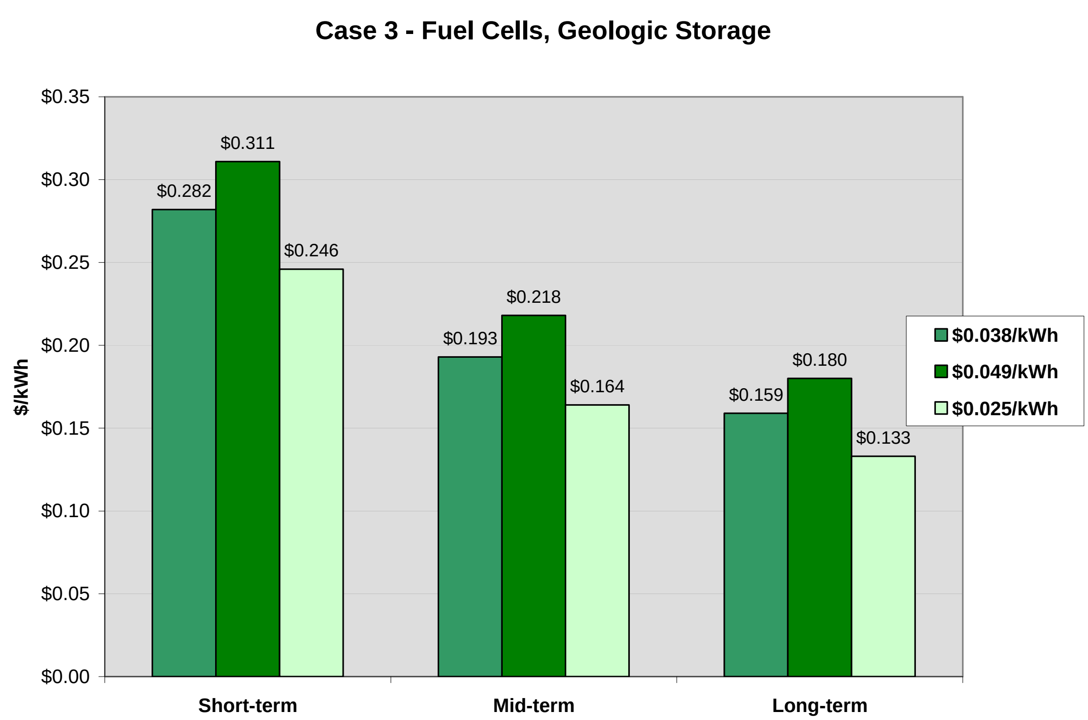

Figure 7. Effect on Storage Cost of Varying Input Electricity Costs

Similarly, assumptions on the cost of non-peak and renewable electricity used to charge the hydrogen-based energy storage system will affect the resulting cost of this energy storage. The base analysis was conducted using an input electricity cost of $0.038/kWh. Figure 7 shows the effect of varying this input electricity cost from $0.025/kWh to $0.049/kWh. As seen below, in the long term optimized Case 3, the resulting electricity storage costs range from $0.13/kWh to $0.18/kWh.

7. Summary

By using information from existing DOE cost models and cost targets for various hydrogen technologies, this study investigated the potential costs associated with using hydrogen as an energy carrier, which could enable electric utilities to use hydrogen-based energy storage systems for load leveling and renewables matching applications.

This study found that on-peak electricity can be produced using a stored hydrogen system in the near-term for 28 to 51 cents per kilowatt-hour. In the long term, improvements in the capital costs and system efficiencies of electrolyzers and fuel-cells could allow on-peak electricity to be produced from hydrogen-based energy storage systems for 16 cents per kilowatt-hour. To put this in perspective, an analysis of electricity production costs developed by Xcel Energy based on typical system costs and utilization rates found that the cost of electricity production by natural gas-fired CTs and advanced turbines (typically used for peak power production) ranged from $0.16/kWh to $0.20/kWh.

As seen in this study, near-term development of hydrogen-based energy storage systems is not expected to be cost-competitive with alternative electricity production options. In the long term however, compared to the marginal electricity production costs cited by Xcel Energy, fully mature and optimized hydrogen-based energy storage systems – whether based on steel tank hydrogen storage or geologic storage (Case 2 or 3) – appear to be cost competitive, if DOE targets for hydrogen technologies are met. More detailed analyses of competing technologies in the mid- and long-term, both of natural gas CTs and of competing energy storage technologies, need to be considered to better understand how hydrogen-based technologies might fare in the future. However, the results of this analysis indicate that hydrogen-based energy storage might hold promise as the performance of hydrogen technologies improve and cost of hydrogen technologies fall.

8. Acknowledgements

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9. References

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